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3 August 2009

Dr John Tamblyn
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Dear John

Review of Energy Market Frameworks in light of Climate Change Policies – 2nd Interim Report

Please find attached the Australian Energy Regulator's submission on the AEMC's 2nd Interim Report for the review of energy market frameworks in light of Climate Change Policies.

Please contact me if you have any questions in relation to the matters raised in our submission.

Yours sincerely,

Michelle Groves
Chief Executive Officer

AER Submission

Review of Energy Market Frameworks in light of Climate Change Policies

Response to AEMC second interim report

3 August 2009

Introduction

The Australian Energy Regulator (AER) welcomes the opportunity to respond to the Australian Energy Market Commission's (AEMC) second interim report for its review of the impacts of the Australian Government's Carbon Pollution Reduction Scheme (CPRS) and expanded Renewable Energy Target (RET) on existing energy market frameworks.

The AER monitors the National Electricity Market (NEM) and is responsible for compliance with and enforcement of the National Electricity Rules (Electricity Rules) and National Gas Rules. The AER is also responsible for the economic regulation of electricity transmission and distribution services as well as gas transportation services. These roles leave the AER well placed to comment on the performance of Australia's energy markets and also on network issues raised by the introduction of the CPRS and expanded RET.

The previous submissions from the AER noted that since the energy market reforms of the past 15 years, Australia's energy markets have generally delivered significant investment and very high reliability.

The AEMC's second interim report has, in the main, appropriately identified the key areas where improvements can be made to the operation of the energy market framework to ensure the efficient integration of climate change policies such as the CPRS and expanded RET.

As noted in earlier submissions, the AER supports the findings that the current energy market framework will continue to deliver timely and efficient generation investment and does not impede the efficient financing of new investment. The AER also agrees with the AEMC's conclusions that the existing electricity and gas frameworks are sufficient to cope with an increased convergence of the two markets.

With respect to retail issues, the AER notes that the Council of Australian Governments (COAG), at its 2 July 2009 meeting, amended the Australian Energy Market Agreement for the pass-through to regulated retail tariffs of both carbon costs under the CPRS and costs associated with the expanded RET. The AER believes that this issue, and any remaining retail issues, can be dealt with through the existing policy processes.

The AER broadly agrees with the AEMC's views as expressed in the questions in chapters 1, 4, 7 and 8. The remainder of this submission focuses on those issues that the AER believes need further consideration in the review.

The submission does not address issues raised regarding the Northern Territory electricity and gas markets. Further, while the AER has not commented on the Western Australian chapters, we note that there are some issues raised in relation to Western Australia that would appear to have broader application to the NEM (such as the payment of ancillary services).

Connecting remote generation (Chapter 2)

The AEMC is concerned that the existing bilateral negotiation framework for generator connection will make it difficult for network businesses to coordinate network connections. It is also concerned that network service providers (NSPs) will not be able to build connection assets to an efficient scale to accommodate future remote generator connections.

The second interim report proposes a new framework for the planning, pricing and funding of connection of remote generation. This framework involves NSPs sizing network extensions for remote generation (NERGs) to accommodate the capacity requirements of anticipated future generator connections. The risk of any asset stranding if the generation capacity forecast is not met will be underwritten by customers.

The Australian Energy Market Operator (AEMO) will have a role in identifying remote areas with high generation capacity (NERG zones) and reviewing NSPs' forecasts of expected generation. The AER will have a role in resolving NERG disputes.

Comments in this submission are focussed on the operation of the proposed connection model. This submission suggests that regulatory oversight is important if the model is to deliver reasonable outcomes for customers.

Application of the preferred option

The AER understands that the AEMC does not intend to exclude any form of generation from this regime; however it would be helpful if this was clarified. Allowing all forms of generation to access this regime would be consistent with the principle of competitive neutrality that underpins the NEM design.

Planning arrangements

The AEMC has proposed that AEMO and NSPs have a role in planning NERGs. AEMO would identify potential NERG zones, while NSPs would size and identify precise locations for NERGs. The AER supports the inclusion of AEMO in the planning arrangements, but has some concerns about the framework for sizing NERGs.

There is no efficiency assessment under the proposed planning arrangements. Instead efficient outcomes rely on AEMO identifying suitable NERG zones and NSPs developing accurate forecasts of generation capacity and sizing NERGs accordingly. However, as discussed below, there is a considerable risk to customers who will be liable for the connection costs which are not recovered by new generation. There are insufficient commercial incentives on NSPs and connecting generators to efficiently forecast and size new network connections, because customers will ultimately pay for any shortfall.

Given this, NSPs' decisions regarding NERGs require regulatory oversight so that the interests of customers are adequately protected. The AER considers that its oversight role should allow the AER to review all proposed NERGs (regardless of whether a party has raised a dispute). The suggested role of AEMO in this process is discussed in the next section.

Locating NERGs

One of AEMO's new roles is to provide a more strategic and nationally coordinated approach to transmission network development. It will oversee the management and development of the NEM transmission system and develop the national transmission network development plan (NTNDP). The AER agrees that AEMO is best placed to identify potential NERG zones and its inclusion in the planning process is a positive development.[1]

It is important that the NERG framework provides AEMO with the scope and discretion to undertake a comprehensive analysis of whether a NERG zone is required. In particular, AEMO should be able to:

- consider the capacity and configuration of the existing network and existing or expected network congestion when identifying NERG zones
- determine whether a NERG zone is sufficiently remote
- consider both renewable and non-renewable generation when developing its forecasts of future generation capacity.

The capacity and configuration of the existing network should be a critical factor that AEMO is permitted to consider when identifying NERG zones. AEMO should have the scope to undertake a network wide assessment as this will identify the areas that are likely to deliver the most efficient outcomes. This assessment would complement AEMO's national transmission planning role and its development of the NTNDP.

AEMO should also have wide discretion when determining which areas are 'remote' from the existing network. The regime should permit AEMO to consider any area where it is likely that a NERG will deliver significant economy of scale benefits, regardless of the distance from the network.

Developing accurate forecasts of future generation capacity

The success of the proposed regime in providing more efficient outcomes than the current connection framework relies on AEMO and NSPs developing accurate forecasts of future generation capacity.

For each NERG zone identified by AEMO, NSPs would be obliged to include design options to service different levels of generation capacity in their Annual Planning Reports. Generators would register their interest in connecting to a NERG through a connection enquiry process. The NSP would then assess the need for any additional generation capacity beyond the generators who have made connection enquiries.

The illustrative example in Appendix F of the second interim report provides a forecast of generation capacity up to 20 years after construction of the asset. While the example

[1] However it is unclear to what extent AEMO's national transmission planning role will aid it in identifying distribution network connected NERG zones, such as the CitiPower and Powercor examples cited by the AEMC in the second interim report.

provided was only for illustrative purposes, in practice it is unlikely that a forecast of this length would have a high degree of accuracy.

Accordingly, the AER considers that the risk of inefficient over-sizing of NERGs should be reduced by limiting the period over which NSPs are permitted to consider generator connections when developing their forecasts of likely generation capacity. The longer the timeframe considered when developing a forecast, the higher the likelihood that actual generation capacity will vary significantly from forecast.

Proposed standard contract and assessment framework

For each NERG, NSPs will be required to publish a proposed standard contract for interested generators which includes the price, terms and conditions of connection. The price will be a capacity-based charge (applying the regulated rate of return) set on the basis of all forecast generators connecting. It appears that the trigger for constructing a NERG is a generator signing the standard contract.

Any party can dispute the standard contract contents within 30 business days and AEMO will have to assess the profile of new generation assumed by the NSP. Under the proposal, the AER would have the option of disallowing a standard contract (and therefore the proposed NERG) where it is not satisfied that:

- the estimates of capital and operating expenditure are efficient
- the depreciation schedule reflects the expected economic life of the assets
- the forecast of expected generation is reasonable.

However, it is unclear from the report whether the AER will always have the option of disallowing a project, or whether this option will only arise when a dispute is raised or AEMO identifies problems with the NSP's forecast.

Regulatory oversight

The AER agrees with the AEMC that the proposed framework requires regulatory oversight as there are limited incentives on either generators or NSPs to optimally size NERGs. Where significant economies of scale exist, the proposed regime provides incentives for generators to overstate the level of expected generation capacity as they are only required to pay for the portion of the asset they use. The AER is keen to ensure that the interests of customers are protected under the proposed framework.

The AER proposes that the regime should require the AER to review *all* proposed standard contracts for NERGs regardless of whether a dispute has been raised. This upfront approval process is similar to the assessment framework for contingent projects and is necessary to afford sufficient protection to customers who may not be able to co-ordinate their resources to raise a dispute.

The AER could consider information and analysis provided by NSPs, advice from AEMO and any concerns raised by interested parties. NSPs' should also be required to apply a high degree of transparency in explaining its methodologies for forecasting future generation capacity and test the sensitivity of any assumptions used in developing its forecasts. AEMO's views would provide valuable input to the AER's consideration of the NERG proposal. Given AEMO's expertise in transmission issues, it should have wide scope to comment on any aspect of an NSP's proposed standard contract, the NSP's forecast of generation capacity and whether the proposal is consistent with NTNDP. The AER should also have wide discretion in the matters it can consider in rejecting a proposed standard contract, including the sizing of the NERG.

Revenue recovery arrangements

Under the proposed framework NSPs will receive a constant revenue stream for NERG assets. Customers will pay for any under recovery in early years, but be refunded in later years as revenue from new generators increases. If forecast generation arrives as predicted, the net impost on customers will be zero over the life of the asset. The AER supports the revenue recovery mechanism sitting outside the regulatory framework and revenue recovery arrangements for prescribed network assets.

The AER also supports the AEMC's proposal of applying the regulated rate of return for determining the standard contract price. Applying a higher rate of return to these assets would only be warranted if a NSP faced a greater exposure to systematic risk associated with the building of these assets, compared to the building of its regulated assets. Under the proposed framework customers bear the risk of any underutilisation. The regulated rate of return is therefore appropriate as a TNSP faces no additional risk associated with building these assets compared to prescribed network assets.[2]

Should NERGs be contestable?

The second interim report canvasses views on whether the provision of NERGs should be contestable. The AER considers that this idea has merit, but agrees that there are significant implementation issues which will need to be resolved if the AEMC pursues this option further. For example the AEMC would need to develop a mechanism for revenue recovery from customers where a non-regulated NSP provides NERG services.

Review of the NERG framework

The AER considers that, if introduced, the new framework for connecting remote generation should be reviewed after an initial period of operation. The review could consider whether the regime has, and is likely to continue, to deliver efficiency benefits to the market. This regime could be reviewed at the same time as the review of AEMO's national transmission planner functions.

[2] Further detail on how the regulated rate of return will apply in practice may need to be considered. For example under the current regulatory arrangements, some of the WACC parameters are determined by reference to a methodology at the time of a NSP's revenue determination. The AER is unsure when these parameters will be determined under the proposed NERG framework.

Efficient utilisation and provision of the network (Chapter 3)

Deep connection charges

The first interim report stated that the current connection framework provides clear locational signals, as new generators must pay direct connection costs and face the risk of being 'constrained off'.

In its submission, the AER raised concerns that the locational signals inherent in the 'non-firm access to dispatch' model were likely to be insufficient to encourage efficient location decisions of new generation plant. It was argued that, with a large amount of new generation capacity likely to connect to the network as a result of the CPRS and expanded RET, the resultant inefficiencies could be substantial.

Accordingly, the AER noted that further models for locational pricing should be considered. Subject to other efficiency considerations, it was suggested that a 'causer pays' principle should apply to both 'deep connection' and 'shallow connection' charges to maintain network capability.

However, the AER recognises that a move to deep connection charges may raise significant questions regarding the treatment of incumbent generators versus new entrants.

The AEMC has correctly identified these issues in the second interim report, with the most concerning being the barriers to new entry that are created and the difficulties in cost allocation recognising the 'lumpy' nature of transmission investments. Acknowledging these issues, the AER agrees that proceeding with an alternative locational pricing framework is preferable to a deep connection model.

Generator Transmission Use Of System Charges

The AER broadly supports the proposal to create charges for generators based on the long run incremental network cost in various geographic zones. While the AER recognises that the generator transmission use of system charges (G-TUOS) proposal is in the early stages of development, comments are provided here to assist in the further development of the model.

Calculating charges

The AER understands that the G-TUOS charge is to be based on the long run marginal network cost of new connections within a G-TUOS zone. The AER supports this approach, together with the revenue neutrality of the proposal.

The AEMC's preferred approach is for the pricing of each zone to be adjusted annually. The AER is concerned that this may conflict with the long run nature of the signals being provided. A typical electricity generation asset has an asset life of 40 years or more. If prices are allowed to adjust year-on-year, it is conceivable that, even if the individual variations in prices are small, the signal could reverse over the life of the generation asset. In other words, a generator may respond to the G-TUOS signal and locate where the charge is negative, however, ten years later this charge may have become positive following a change to load growth or other generator investment decisions. This may lead to the pricing signal being effectively discounted by generators when making decisions on where to locate new plant.

That said, there is a need to ensure that G-TUOS regions and charges continue to reflect the underlying long run incremental network costs. Therefore, there is a balance to be struck in ensuring that the integrity of the pricing signal is not undermined by its ability to change over time (or even reverse), with the need to ensure that charges reflect the underlying costs. It may be possible to address this issue by requiring the entity setting these charges to have regard to the criterion of their long-run stability. This is an issue that should be explored in a future stage of this process.

Number and location of zones

The greater the number of zones created, the more likely that the charges will be able to reflect the actual long run incremental network costs at any location. As such, the previous 17 Annual National Transmission Statement zones would appear to be a logical minimum number of zones. Even this number is likely to be too small as, for instance, there is a single ANTS zone for the whole of Tasmania.

The AEMC proposes that the revenue received from the G-TUOS zones within a NEM region would sum to zero. However, the AER is concerned that this may perverse locational incentives around region boundaries. It is unlikely that G-TUOS zones that sit either side of a NEM region boundary will have the same G-TUOS charge, even though the underlying cost may be the same.

The AER recommends that G-TUOS zones should be determined on the basis of long run incremental costs of the development of the network, without regard to NEM region boundaries. The G-TUOS model could still be revenue neutral, but the charges would sum to zero across the NEM, instead of balancing within regions. This should avoid any perverse locational incentives close to region boundaries.

Additional congestion pricing mechanism

The AER believes that it is worthwhile further developing the additional congestion pricing mechanism. The model currently being discussed appears to closely follow the 'Snowy Trial' Constraint Support Price (CSP) Constraint Support Contract (CSC) approach, for specific areas of acute congestion.

While the G-TUOS model has the potential to provide long term locational signals for the entry of generators, it is not capable of managing congestion after the investment occurs. Accordingly, the AER considers that there is merit in considering a short term congestion pricing mechanism to deal with acute congestion that would operate until the congestion is relieved through network investment, or a region boundary change process is completed.

The AER notes the discussion on the merits of a full nodal pricing model or its variants such as generator nodal pricing or a full CSP/CSC rollout. The AER supports the development of a location-specific time-limited model, in preference to the fundamental changes to market design that would be required with a nodal pricing model. We consider that a comprehensive process for managing congestion can be realised through a G-TUOS charging regime and limited CSP/CSC (with auctioning) mechanism for persistent congestion. We recognise, however, that a location-specific, time-limited congestion pricing model raises administrative issues as to which locations, which generators, or which constraints to include in the congestion pricing regime, and for how long. Forecasting future congestion in advance (for the purposes of deciding which constraints to include in the congestion pricing regime) may prove difficult, running the risk that the regime would end up applying to constraints which are not binding yet would not apply to other troublesome constraints. It may be administratively simpler to introduce a congestion pricing regime which automatically applies to all intra-regional constraints when they trigger pre-defined materiality thresholds.

There are, however, complex issues to be worked through in the development of this model. For example, it is noted that the administrative allocation of rights to the Sydney regional reference node included in the Snowy Trial has been replaced with an auctioning process for the right to access the relevant regional reference node price. While this change is supported in principle, it does raise questions as to how best to deal with situations where there is a single generator sitting behind a constraint. There is potential for issues of market power to develop in these situations. In addition, it is not clear who would be able to bid in the auction for these rights or how the funding arrangements would work.

The AEMC may like to consider establishing some form of working group to examine this model (and the G-TUOS proposal) in more detail. The AER would welcome the opportunity to contribute to such a process.

Generation capacity in the short term (Chapter 6)

The AEMC is concerned that the current reliability mechanisms, including the Reliability and Emergency Reserve Trader (RERT) and AEMO's directions power, do not adequately address the risk of capacity shortfalls in the short term following the introduction of climate change policies. The second interim report sets out a number of amendments or additional mechanisms to strengthen the resilience of the arrangements to respond to this risk.

The AER maintains its view that the likelihood of a potential supply shortfall resulting from an untimely shutdown of existing capacity to be low. The additional risks resulting from climate change policies will not be substantial enough to warrant further interference with market-based outcomes. Additional mechanisms to complement the RERT are therefore unnecessary.

Reserve procurement options

The AEMC's primary concern with the current reliability mechanisms appears to be that they are not designed for frequent use or to procure large amounts of capacity. The AER's view is that none of the additional mechanisms set out in the second interim report provide an effective solution to this problem.

The reliability mechanisms in the NEM are designed to enable a market response through the provision of information and then, as a last resort, for AEMO to intervene if the reliability standard (a medium term average of 0.002 per cent unserved energy) is not able to be met via a market response. Any changes to the framework need to be shown to provide a more efficient way of achieving the reliability standard than the current arrangements.

The reliability standard is operationalised through the establishment of minimum reserve levels for each region. These minimum reserve levels are designed to meet the reliability standard each year in each region of the NEM. The current framework allows AEMO to contract for additional reserves through the RERT when reserve forecasts show that a market response and its direction power are insufficient to achieve the minium reserve level. AEMO can deploy these reserves to avoid load shedding. Where the minimum reserve levels are achieved, either through the market or procurement of reserves by AEMO, the reliability standard should be met over time.

The effectiveness of the RERT to procure reserves up to the minimum reserve level has not been tested since changes were introduced following the Reliability Panel's recommendations in the Comprehensive Reliability Review. These changes were designed to improve the ability of AEMO to source reserve capacity.

Any mechanism that provides for reserves above the minimum reserve level is in effect increasing the reliability standard. The AER notes that there is already a process for the consideration of the reliability standard through the Reliability Panel's reliability review.

Adjustments to the reliability standard should be implemented through subsequent amendments to the market parameter that is designed to provide the target level of reliability—the market price cap.

The use of AEMO's intervention mechanisms to tighten the reliability standard implies a move away from the current framework. However, the AEMC have not yet identified the limitations in this framework that would make this change necessary.

If it is accepted that the RERT is capable of sourcing sufficient reserves to meet the reliability standard, additional intervention in the market can only be justified on the basis it provides more effective management of the load shedding process. There has been no indication, however, that the current jurisdictionally-established load shedding prioritisation processes fail to shed load in an effective manner on the rare occasions that this has occurred.

The market provides the opportunity for any customers who value energy supply at a level below the market price cap to enter arrangements to limit supply at times of high prices (demand side participation). This can occur through direct participation in the wholesale market or through an agreement with a retailer. As the market price cap is set at a level to encourage enough capacity to meet the reliability standard, this should be sufficient to encourage an appropriate level of demand side participation. A standing reserve or load shedding management mechanism is therefore likely to only encourage uneconomic sources of reserve capacity.

The following section sets out the AER's views on each of the options out forward in the report.

Short notice reserve contracting

The AER supports moves to revise the RERT to provide a more timely process for contracting reserves, including the development of a panel of participants and the introduction of a process for short notice reserve contracting. These amendments are likely to provide the market operator with additional flexibility to intervene in the market as needed without significantly adding to market distortions created by the current RERT.

It should be noted that reserve shortfalls that appear at short notice, such as major generator outages, would be relatively rare. The potential for outages at short notice should have already been modelled when determining the appropriate minimum reserve levels.

Standing reserve

The AEMC has defined a standing reserve as a centrally determined volume of reserve, contracted for a number of years, that can be deployed only when the price has reached the price cap and the alternative is load shedding. Both supply and demand side sources of reserve would be accepted.

The AER considers that a standing reserve is unnecessary. A standing reserve is a significant step in the direction of a capacity market (much more so than the proposed changes to RERT discussed above). Such mechanisms may distort signals for new generation investment, and lead to generation capacity and demand-side response options being withheld from the market. As it is not a targeted response, the costs are likely to be far greater than the existing arrangements.

If the existing reliability mechanisms are operated appropriately, a standing reserve would amount to little more than a load shedding management process. As discussed above, this is unlikely to be more effective than the current jurisdictionally-established load shedding priority processes.

Prolonged targeted reserve

A further option set out in the second interim report was for a prolonged targeted reserve. Essentially, this would be an expansion of the RERT to allow contracting further ahead of dispatch under prescribed conditions. The prescribed conditions would include a requirement that the necessary reserves cannot be delivered by the market or through other reliability mechanisms.

As the timeframe for contracting reserves increases, more sources of reserve capacity are likely to become available. However, it has not been established that the nine month contracting horizon in the RERT is insufficient to procure the necessary reserves.

The AER does not support, for the reasons outlined in the discussion of the standing reserve above, any initiatives that allow the system operator to procure medium or long term capacity. These options would fundamentally change the current market design and impact on the efficient operation of the market and incentives for investment or demand side participation.

Load shedding management

The second interim report outlines a load shedding management arrangement, where large users can be contracted to be placed at the top of the load shedding schedule. The AER considers that in practice this mechanism would operate in the same way as a standing reserve, but limited to demand side options. For the reasons outlined in our discussion of a standing reserve above, the AER does not support this option.

More accurate reporting of demand side capability

The AER supports initiatives designed to improve the information that is used by AEMO for determining when to intervene in the market. More generally, the AER supports increased flexibility in the types of information that can be utilised by AEMO in forecasting the demand–supply balance. This could include, for example, historical levels of demand response. AEMO could review and revise its modelling assumptions following high price or low reserve events.

Where the retailer has a demand management contract with a customer, the retailer should be able to pass that information to AEMO without any significant cost. AEMO could then feed the information into its modelling. The AER notes the difficulties involved in this process, particularly the varying firmness of demand side response contracts.

Additionally, if a retailer has a pass-through arrangement with a significant customer (the customer is exposed to the spot price) this information could be provided to AEMO. These arrangements are likely to only apply to a few large customers that may have other obligations under the Electricity Rules. AEMO could then be provided with the ability to further question the relevant customers on their arrangement.

Any information provided by retailers or customers could be done on a confidential basis to protect their commercial interests.

Facilitating distribution connected generation

The AER supports initiatives designed to provide more competition in the market. The removal of regulatory barriers for the connection and utilisation of distribution connected generation proposed by the AEMC are likely to be a low cost means of contributing to this goal.

The AER notes, however, that the dearth of obligations on non-scheduled and unregistered generators may preclude them from fully participating in the market.

System operation with intermittent generation (Chapter 9)

The second interim report outlines potential issues with inertia, voltage control and frequency control ancillary services arising from a substantial increase in intermittent generation. Each of these has the potential to substantially reduce network transfer capability.

In spite of these concerns regarding network transfer capability, the AEMC considers that there are more appropriate avenues for dealing with these issues, including AEMO's network control ancillary services review.

The AER agrees that AEMO is well-placed to determine the technical impacts of intermittent generation on network transfer capability. However, if AEMO identifies that additional mechanisms are needed to maintain network transfer capability, the policy question of who pays for any such mechanism should be clarified in this review. As stated in its response to the first interim report, the AER considers that the current 'causer pays' principle applied to ancillary services, whether centrally contracted or through a market mechanism, should be maintained.

The issue surrounding payment for ancillary services is clearly articulated in Chapter 11 'System operation with intermittent generation in Western Australia' of the second interim report on page 107:

> … [T]he costs of ancillary services may not be fully allocated to those parties causing them. Most ancillary services costs are recovered from load, where as any increases in costs are likely to be triggered by increases in intermittent generation. This is because the variability of intermittent generation is likely to lead to more variations in voltage and to increase the amount of reserve generation required.
>
> As the causers of the need for these services do not see the full costs they create, they are unable to make rational economic decisions to minimise their impact on the system. This will lead to increasingly inefficient outcomes as additional intermittent generation resulting from the expanded RET leads to an increasing need for some of these services.
>
> Stakeholders considered that additional intermittent generation will increase the need for ancillary services, and that the role of Verve Energy in providing ancillary services should be examined. It was suggested that current pricing mechanisms may not provide sufficient signals and that a causer pays regime would increase efficiency.

And on page 112:

> The recovery of costs could also be reviewed, with the aim of more accurately reflecting costs back to causers. Currently intermittent generation has no incentive to notify an accurate position to System Management, and is not exposed to any of the costs that its un-notified and variable output creates.

This discussion applies equally to the NEM.

The AER maintains its view that the recent reforms of 'semi-dispatch' and enhanced wind forecasting systems, that are designed to manage the impacts of increased intermittent generation are, as yet, untested. Their effectiveness will be crucial to ensuring system security. The AER is keen to ensure that a national perspective be maintained in this area and is concerned with the AEMC's view on page 96 of the second interim report that 'In the absence of coordinated action, ad hoc measures may need to be developed.'

Distribution networks (Chapter 10)

The second interim report notes that there is likely to be a period of substantial change for distribution networks in response to the CPRS and expanded RET. While the AEMC has found that the existing market frameworks are sufficiently robust to support changes in the operations (and costs) of distribution businesses, it considers that there may be merit in providing distribution network service providers (DNSPs) with temporary funding to support innovation to manage these changes efficiently.

The AER recognises that the introduction of climate change policies may create new challenges for DNSPs, however it is uncertain about the nature of the problem that the AEMC is attempting to address with this funding. While the report notes that the unpredictability of network flows will make it difficult for DNSPs to meet network performance requirements, it is not clear why the current frameworks are not sufficiently flexible to accommodate this change.

Existing regulatory allowances

As noted in the second interim report, the AER is required to approve a DNSP's proposed revenue allowance where it considers that it is necessary to meet the DNSP's service objectives. The AER does not dictate how this approved ex ante revenue allowance must be spent. To the extent that climate change policies will affect a DNSP's ability to meet these service obligations, the current framework should provide adequate allowances and flexibility for DNSPs to manage this change.

The AER's demand management innovation allowance (DMIA)[3], which has been developed and applied to DNSPs in the ACT, New South Wales, Queensland, South Australia and Victoria, provides additional funding for DNSPs to investigate and conduct broad–based and/or peak demand management projects. The DMIA provides an allowance for DNSPs to research and investigate innovative techniques for managing demand. This could include trials of demand management initiatives which assist in the management of energy consumption decisions and therefore variability of flows across distribution networks.

The DMIA is provided as an annual operating expenditure allowance at the commencement of each year of the regulatory period. The AER's DMIA is designed to ensure the DNSPs have an incentive to spend the allowance on projects that meet the criteria in the scheme. At the end of each regulatory year, the AER assesses the expenditure against the criteria.

To share the lessons learned with the rest of the industry, the AER publishes a report on the demand management projects implemented and the allowance remaining for each DNSP. To encourage DNSPs to spend their allowance, any unspent funds are clawed back from the operating expenditure allowance in the second year of the following

[3] AER, *Demand Management Incentive Scheme—ENERGEX, Ergon Energy and ETSA Utilities,* October 2008; AER, *Demand Management Incentive Scheme for the ACT and NSW 2009 distribution determinations—Demand management innovation allowance scheme*, November 2008; AER, *Demand management incentive scheme—Jemena, CitiPower, Powercor, SP AusNet and United Energy 2011–15*, April 2009.

regulatory period.[4] In addition to the capped allowance, DNSPs are able to apply to the AER for recovery of any revenue forgone as a result of a successful demand management project carried out using the allowance. This is included to offset the decrease in revenue associated with the decrease in sales volume.

The AER also notes that the Australian Government has recently announced that it is providing $100 million to trial large-scale smart grid and smart meter projects. This funding will support the installation of a commercial-scale advanced energy network.[5]

The AER has also included a nominated pass through event in its recent electricity distribution determinations for the New South Wales DNSPs to allow the DNSPs to recover costs associated with meeting an obligation to install smart meters or conduct large scale metering trials.[6]

Additional temporary funding

The AER considers that the development of a temporary funding mechanism for distributors is not appropriate, considering the AER's DMIA and the large trial being conducted by the Australian Government.

The second interim report provides limited detail on the proposed size on the allowance and the types of projects it is intended to cover. It is also unclear how the proposal would sit alongside the DMIA and what distortions would be created by having two competing sources of funds for innovation.

The AEMC should also have regard to the current levels of expenditure, or proposed expenditure on demand management innovation. For example, the recent revenue proposals by Ergon and ENERGEX forecast spending on demand management or non-network alternatives of nearly $40 million per annum combined over the next regulatory period.

It is also unclear how such temporary funding could be included in the short term. The National Electricity Law (Schedule 2, Section 33) would prevent amendments to the Electricity Rules from impacting on existing revenue determinations. Accordingly, it is arguable whether temporary funding could be included for any of the DNSPs who have just had a revenue reset. A similar argument could be made regarding those DNSPs currently engaged in a reset process.[7]

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[4] AER, *Demand Management Incentive Scheme—ENERGEX, Ergon Energy and ETSA Utilities,* October 2008, p. 5–8.

[5] The Hon Peter Garret MP, Minister for the Environment, Heritage and the Arts, '$100 million smart grid trial gets industry talking', Media release, 17 July 2009.

[6] AER, *Final decision—New South Wales distribution determination 2009–10 to 2013–14*, 2009, p. 285

[7] The Queensland and South Australian businesses have just submitted reset proposals. On 30 April 2009 the AER published final distribution determinations to apply to the electricity distribution networks in New South Wales and the ACT, owned and operated by Country Energy, EnergyAustralia, Integral Energy and ActewAGL, for the period 1 July 2009 to 30 June 2014.